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Energy Procedia 1 (2009) 549–556

Energy Procedia

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GHGT-9

Conversion of existing coal-fired power plants to oxyfuel combustion: case study with experimental results and CFD-simulations

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Abstract

Oxyfuel combustion is one of the promising technologies to enable CCS for new and existing coal-fired power plants. For retrofit applications, oxyfuel is an attractive option because it does not have major impact on the boiler-turbine steam cycle. This paper presents a case study for retrofitting oxyfuel combustion technology in large state-of-the-art power plants that are originally commissioned and operated in air-fired mode. The overall process design for the modified power plant is outlined; necessary modifications of relevant components are explained. The paper also discusses results of experiments and numerical calculations on combustion behavior in the furnace. Retrofit measures ensure that the power stations still can run under both air-fired and oxyfuel-fired conditions if required by regulations / market conditions. This provides additional operational and commercial benefits for the operator of the plant and reduces the technical risk of implementing new components and processes not yet proven in the power sector.

Keywords: oxyfuel; oxycombustion; CO2 capture; CCS; coal; power

1. Introduction

Coal-fired power plants with CO_2 capture and sequestration (CCS) are widely expected to be an important part of the future technology portfolio to achieve overall global CO_2 reductions required for stabilizing atmospheric CO_2 concentration and global warming. New coal-fired plants built in the coming years will need to be “capture ready” which means that they can be retrofitted with CCS technologies as these technologies become commercially available and still offer competitive cost of electricity compared to other means of power generation. Oxyfuel

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doi:10.1016/j.egypro.2009.01.073

combustion is one of the promising technologies to enable CCS for new and existing coal-fired power plants. For retrofit applications, oxyfuel combustion is an attractive option because it does not affect the boiler-turbine steam cycle, and with proper design its impact on the boiler fire-side processes and auxiliary equipment can be minimized.

Oxyfuel combustion produces a flue gas stream containing mostly CO_2, which can be directly compressed and purified without further treatment, assuming upstream removal of other pollutants, such as SO_2, NOx and dust. In the process shown in Figure 1 the CO_2 concentration in the flue gas is greatly increased by using a mixture of recirculated flue gas and pure oxygen instead of air for firing coal. Recirculation of flue gas is necessary to provide sufficient mass flow of gas for cooling the flame and also heat capacity and flue gas velocity for convective heat transfer in the boiler.

In the oxyfuel process CO_2 purity is mainly influenced by (a) where the flue gas is recycled in the process (the cleaning that has been done up to this point) (possibilities: 1-6 according to Figure 1), (b) the sealing of boiler and other components (the boiler is still operated at a pressure slightly below ambient pressure for safety reasons), (c) the purity of the oxygen from the Air Separation Unit (ASU), (d) the performance of all air quality control systems (DeNOx, DeSOx, and ESP) (e) additional CO_2 purification during/after compression.

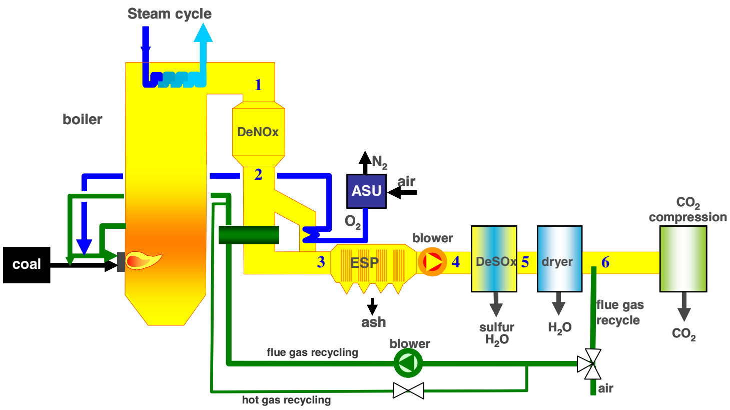


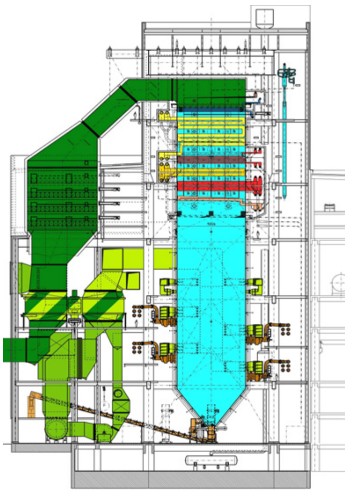
Figure 1: The oxyfuel process

In the following sections, the plant modifications and new components required for retrofitting oxyfuel firing to an existing power station will be described along with the changes in firing and flue gas cleaning processes. A special characteristic of the retrofit measures is that the power station can be operated both with oxygen and air firing after the retrofit. As a result, the plant can be started and shut down in air-firing mode. Also in the event of operational trouble with the new systems, such as CO_2 compression, transport and storage, switching to air firing can be done quickly to ensure reliable electricity supply.

2. Original Power Station: Design for air combustion

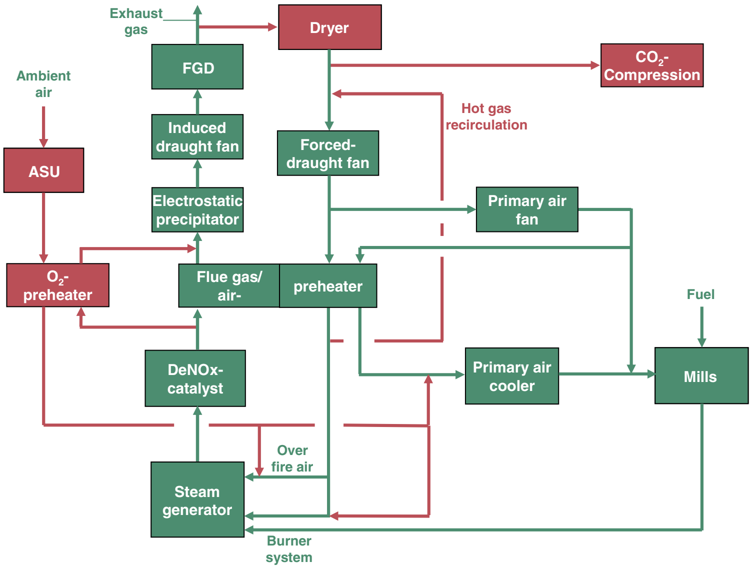
The retrofit measures will be explained based on a state-of-the-art 600°C (1112 °F), 820 MWe power station currently under construction; see Figure 2.

According to Figure 2, during air firing of the power station, the firing air is preheated in the flue gas air-preheater and distributed to mill (primary air), burner and overfire air (OFA) ports. A portion of the primary air enthalpy is used for feedwater preheat in the "mill air cooling cycle". This increases the overall efficiency of the power station process by minimizing cold air to the mill to reduce exit temperature of the flue gas cycle. Additionally, less steam needs to be extracted from the turbine. After combustion the flue gas is cooled in the air preheater, NOx concentration is decreased catalytically, dust is removed in the ESP and SOx is removed using limestone in a wet scrubber. In the boiler the steam is mainly heated by radiation in the furnace and by convective heat transfer in superheaters, reheaters, and economizer in the convective pass.



(a) Once-through steam generator, Benson®
820 MWe / 2088 t/h steam
SH: 600 °C / 276 bar a / RH: 620 °C / 51 bar a
Commissioning: 2011/2012
Design coal: Bituminous Coal

LHV:	25100	kJ/kg
Ash:	13	%
Water:	10	%



(b) Firing process

air case = green components and lines

oxyfuel case = red components and lines added

Figure 2: Power station and design coal (a) and firing process (b)

3. RETROFIT TO OXYFUEL FIRING

Looking at the different options for flue gas recirculation (locations 1-6, Figure 1) it is obvious that the complexity of flue gas recycling is reduced from the progress made in flue gas treatment.

Recycling high-temperature flue gas (before air preheater) is thermodynamically advantageous but requires a total change of the heat balance and a re-design of the plant (boiler and components). A high dust recirculation upstream of the ESP would increase the erosion of all firing and boiler parts. Without DeSOx the SO_2/SO_3 concentration would be increased by accumulation (~factor of 3) and additionally SO_3 formation would increase from contacting with catalytic surfaces. Therefore all firing and boiler components (flue gas and recycle gas ducts, blowers, mill, burners, heat exchangers, boiler materials) would be at risk from corrosion.

For all of these reasons the retrofit concept shown below is based on the recirculation of cold, cleaned and partially dried flue gas after (improved) DeSOx and additional flue gas cooling. This would allow all existing components including blowers and ducts – at least inside the boiler house - to be used after the retrofit. The only measure to be taken inside is to preheat the recycled flue gas up to a temperature well above the saturation point so as to avoid condensation, by re-circulating a small amount of hot flue gas.

Most of the necessary retrofit measures will be implemented outside the boiler house. Switching between oxyfuel and air operation mode can be done simply by using gas tight dampers at the former air inlet where the recycle duct is mounted.

Other changes outside the boiler house involve pure oxygen oxidation in the (improved) DeSOx plant and the addition of a flue gas cooler/condenser (150 MW(th), cooling to 30°C) upstream of flue gas recycling which leads to further reduction of the SO_2/SO_3 content. Downstream of the dryer the flue gas is split and one flow is directed to the boiler house. The duct is connected to the outside air inlet with leak-tight dampers which also provides air in the case of air firing. For oxygen preheating a tubular preheater parallel to the air preheater (now used as gas/gas preheater for the recycle gas) will be installed. By total shutoff of the oxygen preheater, air firing can be enabled even after the retrofit.

The purge gas of the mill is switched to CO_2 and the sealing is retrofitted to ensure that no CO_2 enters the boiler house, the atomizing gas for the aqueous ammonia in the DeNOx is replaced by CO_2 and the ash removal at the ESP is replaced by a gas tight system. A retrofit of the boiler ash removal system is not necessary since a minimum ingress of air is already ensured by a wet ash removal system for the boiler which was implemented during the air firing design.

The modifications minimize the overall leakage/injection of air/nitrogen to the flue gas to 1% of the flue gas mass flow in the furnace. In the oxyfuel mode therefore the flue gas contains about 93 %wt of carbon dioxide as calculated below. The mass flow is reduced to 25 % of flue gas flow leaving an air-fired furnace. Purification and compression of this CO_2 rich flue gas is the last step of the oxyfuel process. During compression some of the remaining contamination gases, such as NOx and SOx, are separated during and leave the process as condensate from the intermediate coolers as sulfuric and nitric acids. Most of the water is also removed from these intermediate coolers. Normally there is no other purification step since other trace gases such as nitrogen, oxygen and argon can remain in the compression stream for storage. To also remove these gases (depending on the use/storage option) cryogenic separation would be necessary. However, water has to be removed down to very low values to prevent corrosion in pipelines and tanks.

The only commercially available and proven technology today to supply an 820 MWe bituminous coal fired power plant with oxygen is the cryogenic process. In this case up to 13,500 t/d (including 10% reserve) of oxygen is required. The available size and required control range of air separation units (ASUs) will make 4 ASU lines necessary. The space required for this plant is roughly 2.6 hectares. An important issue is the load change rate of an ASU which typically is limited to 1%/min but the rate of a power plant, depending on the “grid code”, is up to 5%/min. To compensate for this difference, a temporary buffer storage is necessary.

4. Thermal Engineering and Combustion Technology

To prevent significant changes to the power plant heat balance, it must be assured that the heat transfer in furnace and heat exchangers in the convective pass match the original design. Additionally, the material temperatures have to be kept in a tolerable range and the steam temperatures and pressures should match the air combustion case. These requirements are fulfilled by the adjustment of the mass flow of recycled flue gas and split in gas for burner (primary gas and other), overfire air and curtain gas as well as the adjustment of the oxygen content in different gas flows. The furnace exit gas temperature is set according to the upper limit given by the ash melting temperature.

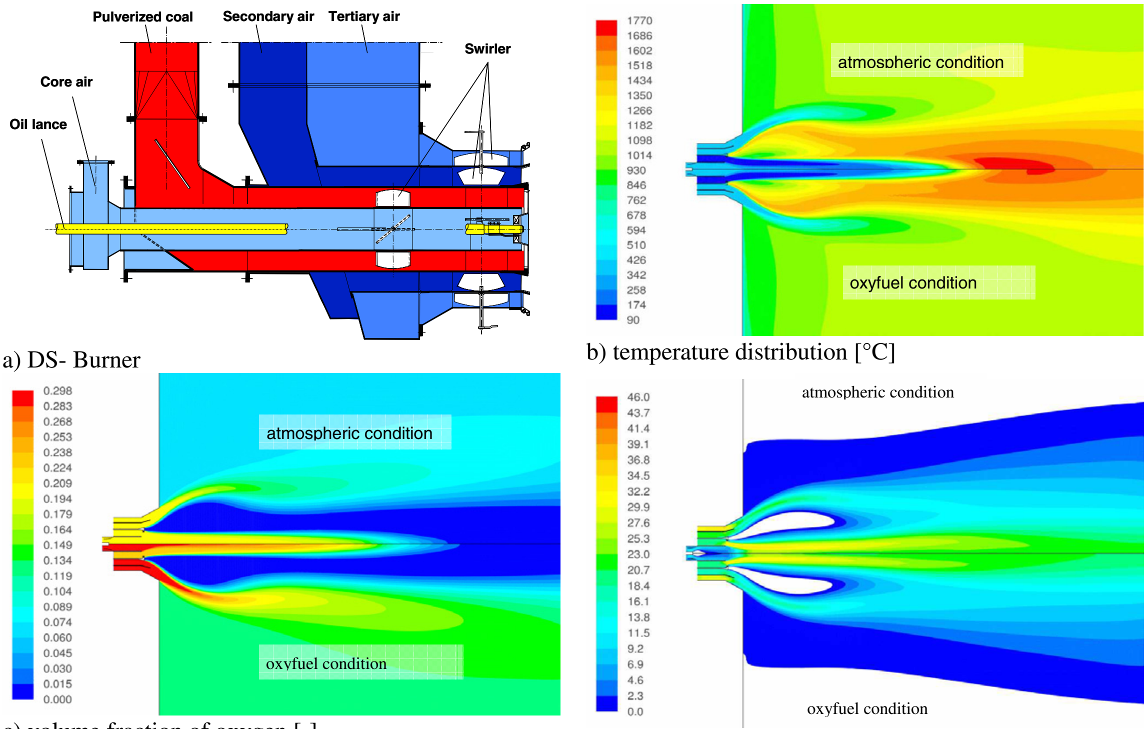
During the redesign under oxyfuel conditions the firing components (mill, burner) are recalculated as is the heat transfer in furnace and heat exchangers with respect to the changed flue gas properties so as to determine the optimal process parameters. For the retrofit case the modifications of existing components are minimized so as to reduce plant outage time.

4.1. Burner

An important criterion for mill operation is the discharge of particles by flue gas. The dominating force is the flow resistance which depends on temperature and composition of the carrier gas and therefore the mass flow required for the transport of the fuel particles depends on location. The calculations proving that the gas streams can carry the fuel particles have to be carried out at least at the mill nozzle ring, upstream and downstream of the classifier and in the ducts. The volumetric flow has to be the same as for air firing operation to get a reliable and steady flow downstream of the classifier. The lower velocity at the nozzle ring in this case is compensated by the higher gas density.

The power station studied here uses Hitachi Power Europe’s low NOx DS burners (Figure 3a). Except for the primary gas flow, which has to be adjusted to the mills' needs, the momentum gas flows at the burner are kept constant in the retrofit case so as to get a flame shape similar to that in the atmospheric mode.

The flame temperature and burnout progress are adjusted to fulfill the needs of heat transfer utilizing the oxygen concentration as a variable. This is demonstrated by the findings from a rotational symmetric flame calculation.



a) DS- Burner

b) temperature distribution [°C]

c) volume fraction of oxygen [-]

d) axial velocities [m/s]

Figure 3: Low NOx DS burner (a) and results from CFD calculation results (b-d)

Figure 3b depicts the difference between the temperature distribution of atmospheric and oxyfuel-fired flames. Whereas the upper half shows the temperature distribution of the atmospheric flame, the lower half reveals the findings for oxyfuel conditions. The difference is very small under the examined conditions. This shows that the chosen parameters for the oxyfuel case are appropriate for getting firing conditions inside the furnace similar to those under atmospheric conditions.

It should be pointed out that the flame temperature is very much affected by the volume fraction of the oxygen in the oxygen carrying gas. The volume fraction is shown in Figure 3c. Here the oxygen concentration is chosen to match temperature distributions of air and oxyfuel firing as shown in Figure 3b. The often discussed decrease of oxyfuel flame temperature is countered by increasing the volume fraction of oxygen in the oxygen carrier gas.

Comparison of the axial velocities (see Figure 3d) shows that the rule for the momentum for the oxyfuel conditions really does result in similar flow fields for atmospheric and oxyfuel flames. In this figure, the white zones represent backflows. The backflow zone behind the tooth-ring of the primary air tube has nearly the same shape in both the atmospheric and oxyfuel modes. This backflow zone is essential for burner ignition purposes.

4.2. Heat balance

The mass flow of gas in the OFA system is adjusted so that the heat transfer in the convective pass matches the values of the original design. As is shown in Table 1 the flue gas density in oxyfuel firing is increased by 35%, the heat transfer coefficients for convective and radiative heat transfer by 2.7 and 38.3% respectively and the flue gas mass flow by 3.9%. These increases are partially compensated by a 17K or 5.2% decrease of the logarithmic temperature difference. The flue gas recycling rate is 75.1% and the overall stoichiometric factor 1.17 (upstream of air heater). This is equivalent to an excess of oxygen at the end of the furnace of 2.86 wt.% wet.

Table 1: Heat transfer in convective pass (average values for entire convective pass)

ΔOxy/Air mode * 400-1200°C	Air mode	Oxy mode		ΔOxy/ Air mode [%]
flue gas density ρ_{FG}	1.33	1.80	kg/m³ (STP)	35.0%
heat capacity of fg* $c_{p.FG}$	1.23	1.29	kJ/kgK	4.7%
dyn. viscosity of fg* η_{FG}	42.87	40.84	µPa s	-4.7%
heat conductivity of fg * λ_{FG}	0.07	0.07	W/mK	2.8%
mass flow of flue gas m_{FG}	716.70	744.85	kg/s	3.9%
max. flow velocity w	10.70	8.00	m/s	-25.2%
ΔT(logarithmic)	318.20	301.80	K	-5.2%
α (convection) $\alpha_{outside.convective}$	38.88	39.91	W/m²K	2.7%
α (radiation) $\alpha_{outside.radiation}$	34.98	48.36	W/m²K	38.3%
K (heat transfer coefficient)	51.02	60.26	W/m²K	18.1%
Total heat transfer in convective pass Q	705.83	741.51	MW	5.1%

4.3. Furnace

CFD-simulations of both the atmospheric and Oxyfuel modes were made, which allow for the comparison of the different conditions in the furnace. The furnace geometry simulated is shown in Figure 4. In the vertical section of the temperature field in Figure 5a and 5c the positions of the individual burners can be clearly recognized in both operating modes by their relatively cold inlet flows. At the same time the high temperature gradients clearly reveal the burner ignition zones. As the chosen conditions lead to similar flame shapes, the temperature distributions in both operating modes are very similar especially at the burner levels. The lower mass flow through the OFA system in the Oxyfuel mode leads to a slight tilt in the temperature field above the burner levels (see below). At the furnace exit the temperature distribution is homogenized by the pressure loss induced by the convective section above the furnace. The furnace exit gas temperature is similar to that in the air combustion case.

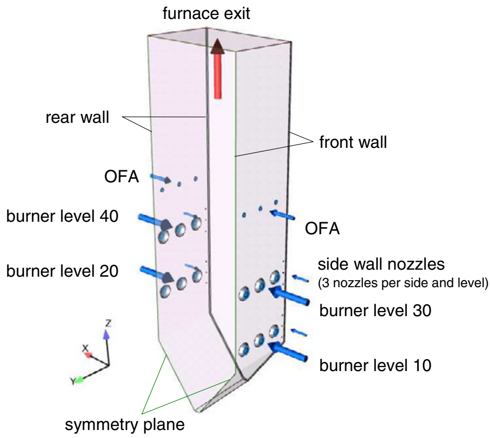
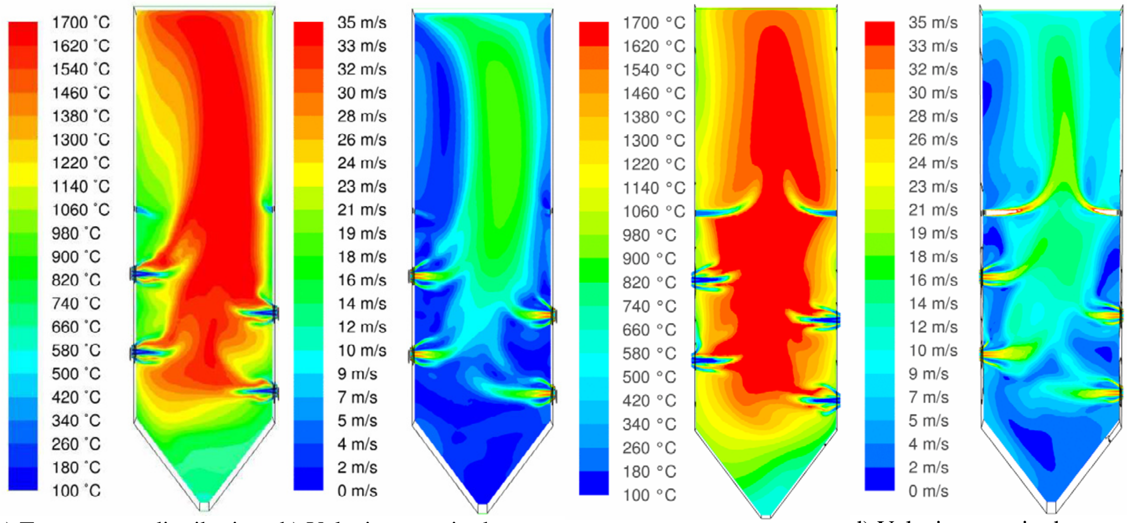


Figure 4: Furnace geometry

The flue gas flow velocities in the furnace are shown in Figure 5b and 5d. The positions of the burners can be clearly identified from the high velocities there with nearly equal values both in oxyfuel and atmospheric mode. It can also be seen that in Oxyfuel mode the low mass flow through the OFA system has no significant impact on the flow in the furnace. Therefore due to the staggered burner levels the hot flame gases are directed somewhat more to the front wall than in the atmospheric mode. This effect could be overcome by a lower mass flow through the top burner level than through the level below. In atmospheric mode the highest velocities, which lie beyond the scaling, exist at the OFA system. The high mass flow through the OFA system counteracts the slight tilt induced by the staggered burner levels.

In general the CFD-Simulations show similar conditions in both the atmospheric and Oxyfuel modes, thus the operation of the furnace in Oxyfuel mode is rated as uncritical.

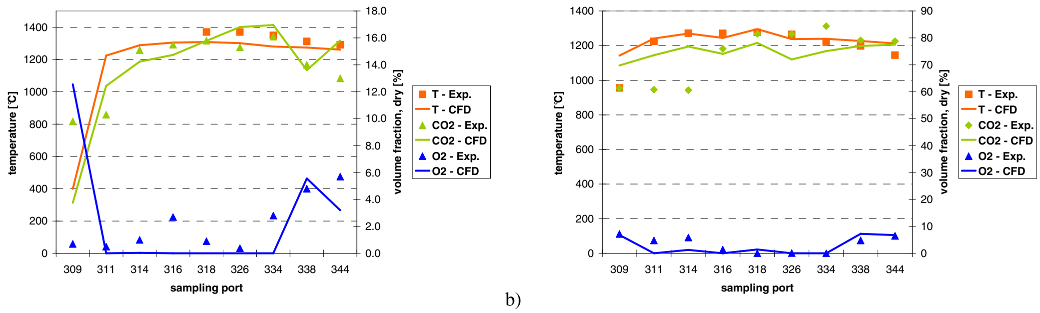


a) Temperature distribution - Oxyfuel mode
b) Velocity magnitude - Oxyfuel mode
c) Temperature distribution - atmospheric mode
d) Velocity magnitude - atmospheric mode

Figure 5: Simulated temperatures and velocity magnitudes in Oxyfuel and atmospheric mode

4.4. Combustion test facility

Experiments and CFD-simulations on a 1 MWth combustion test facility were made both in atmospheric and in Oxyfuel mode. Figure 6 shows, that the mass fraction of important species like CO_2 and O_2 in the furnace can be predicted by the simulations as well in atmospheric as in Oxyfuel mode. Some minor differences from the experiments occur because of uncertain boundary conditions. The OFA nozzles were partially blocked in air mode, which directed the oxidizer stream towards the ports 314-318 and lead to a higher O_2-volume fraction. In general the use of CFD-simulations to examine the combustion behavior in atmospheric and Oxyfuel mode is valid.



a) b)

Figure 6: Comparison of experimental and numerical results: a) Air mode; b) Oxyfuel mode.

5. SUMMARY

The process engineering for retrofitting a power plant to oxyfuel firing to enable CO_2 capture after the combustion process is described in this paper. The flue gas composition for normal air firing and oxyfuel firing is shown in Table 2. The concentration of CO_2 in the flue gas after cooling is nearly 95 wt% (db.) in the case of oxyfuel firing. This gas can be directly compressed and directed to the storage site without further purification.

The required area for the new components as well as the demand for electrical energy and cooling capacity is shown in Table 3. The required area for AQCS modification is rather small compared to the ASU which has to be installed as new. Nevertheless, the ASU can also be constructed at some distance from the power station when the oxygen is transported to the boiler house by pipeline. Hence, there is normally enough space for the remaining modifications on the site. The arrangement of the new components and plant modifications is shown in Figure 7.

Table 3 also provides the energy requirements for a number of modifications. The ASU and compressors require a large amount of electrical energy. Using the numbers given, the gross electrical output of the power plant in the worst case is reduced by more than 24%.

Table 2: Comparison of flue gas composition

gas species	air firing (Composition after ESP) wt % wet	wt % dry	oxyfuel-firing (Composition after cooling) wt % wet	wt % dry
H_2O	5.9	-	4.8	-
CO_2	19.4	20.6	89.9	94.9
N_2	68.7	73.1	2.0	2.1
O_2	4.5	4.7	2.9	3.0

Table 3: Additional demand of electricity, cooling duty and area after retrofit

	area required [m²]	P_{el} [MW]	Q_{th} (cooling) [MW]
ASU	26000	107	117
Cooling & AQCS modifications	900	4	150
CO_2 Compression	2000	85	

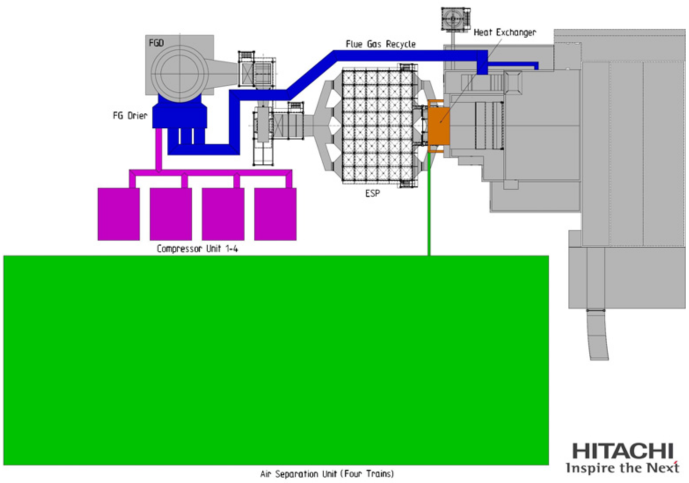


Figure 7: Arrangement for retrofitted power station

In conclusion, existing state-of-the-art coal-fired power stations can be converted to oxyfuel combustion with no change to the plant water-steam cycle and minimal modifications to the boiler house. Limited alterations to the air quality control system are needed. Major equipment additions for the air separation and CO_2 compression and handling are necessary. The converted power plant will have the flexibility to operate in both air-fired and oxyfuel modes.

While it has been shown that retrofitting existing power plants is technically feasible, all processes have to be further optimized in future to reduce the cost and efficiency penalty of CCS. Hitachi is currently undertaking extensive development work to improve basic technologies for oxyfuel combustion and other CCS options. This is being done so as to supply highly efficient, overall solutions for CO_2 lean fossil fuel power stations to the global market as a contribution to society by combating climate change.